APPENDIX A **7-Dec-04**

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

Key Data Elements and Assumptions	Assumption Used in this Analysis	Alternative Potential Sources of Information, Data, and/or Critical Assumptions		
		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
Number of Sites Impacted				
Number of wells drilled per year	Uses forecast well counts in the EIA 2004 AEO Reference Case Forecast -- average about 26,400 wells per year from 2003 to 2025. (Reference 9) This includes both successful and dry wells. However, it does not consider the fact that, in some cases, multiple wells are drilled from a single pad. However, this is the exception, not the rule. To indicate this, in 2002, of the 23,955 onshore wells drilled in the U.S., 890 were horizontal wells, and 705 were sidetrack wells (Reference 11), or approximately 6-7% of the total wells drilled.	Analysis by Texas Alliance of Producers based on 2001 drilling levels of nearly 32,000 wells per year (Reference 8). The most recent NPC natural gas study's (Reference 14) forecast of gas well drilling is comparable to the 2004 AEO (the NPC did not report a forecast for oil well drilling).	EPA's analysis did not explicitly examine "construction activities" in the oil and gas industry distinctly, but lumped these activities with all other "construction activities" considered.	DOE generally tends to use the most recent EIA forecast, usually the most recent Reference Case from the latest AEO.
Number of injection wells	Estimates of the number of injected wells in the U.S. are based on the ratio of operating injection wells to oil production wells in Texas and California. This results in approximately 1 injection well for every 4 oil production wells. This includes all enhanced recovery (both water and gas injection) and brine disposal wells, but not injection wells used for gas or hydrocarbon storage. All injection well sites were assumed to fall within the 1-to-5-acre size category.	Rough estimates nationally, using EPA data for Class II injection wells. (http://www.epa.gov/safewater/uic/classii.html), which includes storage wells, and *World Oil* magazine estimates (Reference 15) of producing oil wells in the U.S., would make this number more like one injector for every 3 oil production wells, implying the 1 in 4 estimate may be somewhat conservative.		DOE generally uses EPA estimates of the number of Class II injection wells nationally.The 1990 DOE Cumulative Impacts Study assumed 172,000 injection wells nation-wide, based on work for API during the Class II program mid-course correction process. At the time, this compared to 420,486 producers, or one injector to every 2.44 oil production wells.
Number of construction sites associated with gas gathering activities.	This analysis used the Gas Processors Association recommendations. For purposes of this analysis, this number is assumed to be applicable annually.	The Gas Processors Association estimates that there are currently approximately 2,370 projects in the natural gas midstream sector that would fall between 1 and 5 acres (Reference 13).		

APPENDIX A

7-Dec-04

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

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Number of construction sites associated with gas transportation activities.	Estimate based on the number of current projects estimated for one company that would fall under the new requirements in the 1-5 acre range. Using the estimated miles of gas pipelines within this company, to which this number applies, it was determined that there would be an estimated one 1-5 acre project falling under the new requirements per 278 miles of pipe. Based on the number of miles of natural gas and liquid pipelines in the U.S., this would amount to about 1,500 sites per year, assumed to be applied annually.	The one company developed their estimate based on the number of currently permitted projects (under Phase I requirements), compared to the estimated number of projects they have in the 1 to 5 acre size range. This included both identified projects and an estimate of the number of projects that are currently “unidentified,” but that were determined to be likely based on the number of identified projects.Company requested that they remain confidential.		
Portion of Sites Impacted				
Estimated proportion of sites impacted	For this exercise, uses the number of sites estimated above as the unit for analysis; assuming other facilities are > 5 acres or < 1 acre, and therefore not subject to the new requirements. In reality, for example, some well sites are > 5 acres, especially where associated facilities, such as gathering systems, production processing facilities, tank batteries, etc., are included. The analysis assumes all well sites are within 1-5 acres, and the separate construction projects associated with gathering system and pipeline-related activities are in addition to those associated with a well site.	No explicit assumptions stated, but most industry commentors expressed concern that essentially all sites would be impacted.	EPA's analysis did not explicitly examine "construction activities' in the oil and gas industry distinctly, but lumped these activities with all other "construction activities" considered.	

APPENDIX A

7-Dec-04

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

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Portion of wells subject to new requirements	EPA states that 41% of nation's acreage is in states with existing state programs that would not have to be modified to meet new requirements under Phase II (Reference 2). Therefore, in the Base Case, it was assumed that 60% of the sites (wells, gathering facilities and pipeline projects) would be subject to the new requirements. In the Higher Impact Scenario, given industry concerns, it is assumed that 90% of the sites would be subject to the new requirements.	On a well basis, roughly 60% of the wells drilled in the U.S. in 2002 were in states where EPA would have regulatory authority or where the wells would likely be drilled on federal lands (Reference 11). Many in industry, however, believe that nearly all wells (over 90%) in the country would be subject to the new requirements. For example, EPA is the jurisdictional agency for gas pipeline construction activities in three of the major oil and gas producing states -- New Mexico, Oklahoma, and Texas. Of the nine states which manage the storm water permit program, eight have adopted EPA's 2 year postponement: Arkansas, Colorado, Illinois, Iowa, Kansas, Louisiana, Nebraska, and Wyoming. Several of these are major oil and gas producing states. The one remaining state, Missouri, has developed a state program. Since all of these states have followed EPA's lead on the postponement for the oil and gas industry, it is reasonable to assume that they will follow EPA's lead on implementation of the Phase II permit requirements to the oil and gas industry.	States w/ EPA oversight that produce O&G include TX,OK, NM,AZ,ID,AK, Native Lands. In the Development Document for this rulemaking (Reference 2), EPA estimates that 41% of developed acreage is in states with existing state programs, and would not have to modify their permits to meet the new requirements (Reference 2). In answers to questions posed by the White House Energy Task Force in 2002, EPA cited numbers of 4,000 impacted well sites in OK, 8,000 - 9,000 in TX (Reference 5). I	.
Erosivity factor waiver	For this analysis, it was assumed that 15% of sites will receive <u>either</u> an erosivity factor or TMDL waiver (Reference 5), beginning in 2005. The Higher Impact scenario assumes that no sites are subject to either waiver.	Some in industry claim that few, if any, sites would likely be subject to such waivers. Permitting authorities have the option to not allow waivers. In many cases, the times of year during which the waivers could be obtained are minimal and sporadic. Moreover, a waiver may not necessarily waive <u>all</u> permit requirements, but only allows EPA to waive "otherwise applicable requirements in a general permit." Finally, should operators try to schedule drilling to coincide with time windows during the year when waivers could be obtainable, it could further complicate the logistics of leasing, permitting, and scheduling drilling rigs	In EPA's response to questions from the White House Energy Task force (Reference 5), EPA estimates that 15% of sites in TX and OK would be eligible for a waiver, based on the ICR conducted as part of developing the Phase II requirements.	

APPENDIX A

7-Dec-04

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

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TMDL waiver	For this analysis, it was assumed that 15% of sites will receive either an erosivity factor or TMDL waiver (Reference 5), beginning in 2005. The Higher Impact scenario assumes that no sites are subject to either waiver.	No explicit assumptions stated.	No explicit assumptions stated.	
Portion of facilities subject to ESA review	Based on EPA assessment, assumes 40% of sites would have endangered species in proximity and would require ESA review (Reference 2). This was assumed for both the Base Case and Higher Impact scenario.	Industry believes that nearly all sites in the country would have to conduct some type of ESA review to comply. Some are also concerned that drilling opponents or reluctant landowners will use the process to delay or stop drilling; implying the portion subject to review could be considerably higher than that assumed by EPA. Furthermore, a brief filed by the National Resources Defense Council (NRDC) in the 7th Circuit on July 28, 2004 argues, among other things, that the self-implementing ESA provisions of the CGP should not be allowed under the ESA, and that EPA should be required to review each operator's ESA and, in consultation with USFWS/NMFS, determine that no adverse effects are likely to any endangered species in the project area	EPA's Phase II ICR determined that 60% of all "small construction projects" nationwide would have no endangered species in proximity (so 40% would be subject to ESA review). (Reference 2).	
Portion requiring ESA consultation	Based on an EPA assessment, assumes 3% of sites would have endangered species in proximity and would require ESA consultation (Reference 2). The Higher Impact scenario assumes that 15% of sites would require consultation, based on endangered species in proximity and/or assuming challenges by landowners or others to initial ESA determinations.	No explicit assumptions stated, though, like that above, some are concerned that drilling opponents or reluctant landowners will use process to delay or stop drilling; implying the portion subject to consultation could be considerably higher than that assumed by EPA.	EPA's Phase II ICR determined that 3% of all "small construction projects" nationwide would have endangered species in proximity and would require consultation (Reference 2).	

APPENDIX A **7-Dec-04**

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

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		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
Portion of facilities subject to NHPA review	Since a NHPA review is currently not addressed in the Construction General Permit, no NHPA review is assumed to be required in the Base Case. In the Higher Impact scenario, 20% of sites are assumed to require review, based on the OK experience.	In OK, according to industry comments (Reference 6) , local office requires evaluations on 805 of requests (out of about 4,000 wells), even though in only small portion will historic sites be discovered.	In the draft Phase II requirements, provisions were proposed to require storm water discharge permit applicants to conduct historic or archeological reviews to ensure the protection of historic places under the National Historical Preservation Act (NHPA). However, the final CGP does not include these requirements. However, EPA is continuing discussions with the Advisory Council on Historic Preservation on potential future requirements. The current CGP contains a “re-opener clause” which can allow EPA, at a later date, to modify the CGP based on those discussions.	
Portion requiring consultation	The Higher Impact scenario assumes that 10% of sites would require consultation, based on important sites in proximity and/or assuming challenges by landowners or others to initial NHPA determinations.	No explicit assumptions stated.	No explicit assumptions stated.	
Required activities imposing costs				
Submitting NOI, preparing SWPPP, implementing Best Management Practices (BMPs), and performing post-construction inspections.	Process of submitting NOI will involve efforts to certify SWPPP has been completed, BMPs installed according to SWPPP, periodic inspections have been completed, and the site has been stabliized prior to filing NOT. Assumes 72 person-hours, at $75,000/year salary, and associated overhead. Amounts to $6,000 per well.	Total increase in cost per well estimated by Texas Alliance of Energy Producers to range from $3,000 to $8,000 per well. One company estimates the costs to be on the order of $7,000, and the Gas Processors Association (Reference 13) assumes costs on the order of $5,300.	EPA estimates that it will take approximately 16 hours, for sites 10 acres and smaller, to certify SWPPP has been completed, BMPs installed according to SWPPP, periodic inspections have been completed, and the site has been stabliized prior to filing NOT.	In DOE's Environmental Metrics Analyses (2000), assumed that $1,000 would be required to submit NOI and implement SWPPP, and $2,560 would be requried to establish soil erosion control for a 2-acre site (Based on 1997 EPA analysis of Phase I rulemaking.) No costs assumed for post construction inspections.

APPENDIX A

7-Dec-04

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

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		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
Obtaining ESA clearance	For ESA review, assumes 36 person-hours, amounting to $3,000 per well. For consultation, assumes 160 hours, amounting to $13,333 per well. Higher Impact scenario assumes consultation requires twice as much effort, at a cost of $26,667	In the NPC study (Reference 14), costs for conducting an intensive field survey for threatened and endangered (T&E) species, or candidate T&E species, were estimated as $3,500.	No explicit assumptions stated.	
Obtaining NHPA clearance	Under the Higher Impact scenario, for NHPA review, assumes 48 person-hours, amounting to $4,000 per well. Assumes consultation requires 320 hours, at a cost of $26,667	In OK, only "approved archeologists can be used. Typical review will cost $3,000 to $5,000, depending on complexity of the site. NPC study (Reference 14) estimates costs for Class III survey with no resouces to be $1,500 to $4,000, and up to $6,000 if sites are present. Consultation costs, if requiring a date recovery and treatment plan, are estimated at $10,000 minimum, but could be as much as $250,000 per site for implementation.	No explicit assumptions stated.	
Required activities imposing delays				
Individual review of NOIs and SWPPPs, and allowance of public participation	In this assessment, the implications associated with the NRDC recommendations were not considered, but if NRDC were to prevail, the case-by-case review and public participation requirements they seek to impose would increase still further the already very significant potential of the CGP requirements to delay oil and gas drilling, increasing the potential for lease forfeiture and lost reserves.	NRDC argues that the general permit does not comply with the CWA because EPA does not individually eview the NOIs and SWPPPs prepared under the general permit process and the permit process does not provide for public notice, comment, and opportunity for public hearing ("public participation") on NOI's and SWPPPs. NRDC made the public participation argument with to the Ninth Circuit with respect to NOIs submitted for stormwater discharges from Municipal Separate Storm Sewer Systems (MS4s), and won in Envt'l Defense enter v EPA, 344 F.3d 832, 856-58 (9th Cir. 2003). .		

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

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		Industry/NGOs	**EPA (2002) Economic Impact Assessment**	**Prev. DOE Assumptions**
Obtaining ESA clearance	Assumes some delay in expectations could be "scheduled" in terms of rig contracting. For purposes of this analysis, assume 7 days of "unscheduled" delay for review, 21 days of "unscheduled" delay for consultation (due to large increase in workload on existing goverment staff, without any increase in staffing levels). Higher Impact scenario assumes that this process could be three times longer.	Currently, when consultation is required, USFWS is allowed 90 days to consult, and 45 days to prepare biological opinion. In 2002, industry comments stated that USFWS consultation requires 45 days or longer. Longer delays anticipated due to the substantial increase in workload due to new requirements, and shortage of available staff to perform reviews. The Texas Alliance of Energy Producers estimates typical delays in construction and development of from 1 to 4.5 months (Reference 8). Another operator (wishing to remain anonymous) stated that a routine consultation could take from 6-12 weeks, and with adverse parties involved, could take 3-6 months or more.		
Obtaining HP clearance	Assume some delay expectations could be "scheduled" in terms of rig contracting. For purposes of this analysis, assumes, under the Higher Impact scenario, based on OK experience, assumes a 30 day delay for review, and 90 day delay for consultation.	Industry concerns are that timing delays are likely with historical preservation and historical reviews. In OK, operators typically incur delays on order of at least 30 days. (Reference 8)	No explicit assumptions stated.	
Other Pertinent Data/Assumptions for Estimating Potential Impacts				
Oil and gas price assumptions used for estimating impacts	Uses EIA oil and gas price forecasts based on the EIA 2004 AEO. Oil prices average $25/Bbl over 2003-2025 time period, gas prices average nearly $4.00/Mcf over same time period (Reference 9).	Industry based its analysis on average 2001 wellhead prices of $21.66/Bbl of oil and $4.12/Mcf of natural gas (Reference 8).	Not considered in EPA's economic impact assessment.	DOE generally tends to use the most recent EIA forecast, usually the most recent Reference Case from the latest AEO.

APPENDIX A **7-Dec-04**

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

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Drilling day rates associated with idle rigs waiting for approval from ESA and/or NHPA review	Assumes average drilling costs (for all wells) for 2002 as reported by API, or $711,000 per well (Reference 11). Over the 1995-2002 time period, the average rig utilitzation rate was 70% (Reference 12). This was used for estimating rig day rates, resulting in an average drilling day rate of ~$2,800 per day.	No explicit assumptions stated.	Not considered in EPA's economic impact assessment.	
Average reserve additions per new well drilled (used for estimating the value "lost" due to production delays).	Based on EIA forecast drilling levels and reserve additions for oil and gas in the 2004 AEO Reference Case. On average, over the 2003-2025, a typical well drilled will add ~ 85,000 BOE of new reserves (Reference 9).	No explicit assumptions stated.	Not considered in EPA's economic impact assessment.	
Industry average discount rate (used for estimating the value "lost" due to production delays).	According to EIA's Performance Profiles for Major Energy Producers, 2002 (Reference 10), FRS reporting companies earned an annual return on investment for domestic O&G production of 13.3% in 2001 and 6.1% in 2002. The average of these -- 9.7% -- was used in this analysis (for estimating the value of delayed production). This amounts to a daily discount rate of 0.0266%.	No explicit assumptions stated.	Not considered in EPA's economic impact assessment.	

APPENDIX A

7-Dec-04

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

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Discount rate of estimating economic impacts	For this study, a discount rate of 5 percent was selected as a reasonable "mid-point" rate based on the literature reviewed.		Choice of the discount rate is one of the most controversial and important topics within cost-benefit analysis. The available literature was reviewed to provide some insight into the choice of a discount rate to use in this study. The Office of Management and Budget (OMB) recommends a 7 percent discount rate for social benefit-cost analysis (References 17 and 18)]. In an EPA report of guidelines for its economic analyses [Reference 19], a 3 percent discount rate is recommended. However, EPA's recent financial impact analysis of the Clear Skies Act uses a 5.3 percent discount rate [Reference 20] and their benefit analysis of the Clear Skies Act forecasts benefits using both a 3 percent and 7 percent rate [Reference 21].	
Portion of wells experiencing increased royalty costs associated with project delays; and impact of those increased rates	Assumes Henry Petroleum estimated 5% of wells will have to pay increased royalties, with an increase of 2.5% in the royalty rate (Reference 3). Higher Impact assumes that 10% of wells have to pay increased royalties.	Henry Petroleum presentation estimates that 5% of wells will have to pay increased royalties, with an increase of 2.5% in the royalty rate (Reference 3)	Not considered in EPA's economic impact assessment.	
Average daily prodution rate per well	Average daily prodution rate per well assumed to be 13 BOE/day for oil and gas wells (Reference 9)			
Portion of wells experiencing forfeited lease bonuses and rentals associated with project delays	Uses Henry Petroluem estimate of 5% (Reference 3) Higher Impact scenario assumes 20%	Henry Petroleum presentation estimates that 5% of wells will forfeit bonuses (Reference 3)		

APPENDIX A

7-Dec-04

CRITICAL FACTORS AND KEY ASSUMPTIONS CONTRIBUTING TO THE ECONOMIC IMPACT OF POTENTIAL NEW STORM WATER DISCHARGE REQUIREMENTS

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Lease rental cost	Uses Henry Petroluem estimate of $25/acre (Reference 3)	Henry Petroleum presentation estimates rental costs of $25/acre (Reference 3)		
Lease bonus cost	Uses Henry Petroluem estimate of $100/acre (Reference 3)	Henry Petroleum presentation estimates that lease bonus costs of $100/acre (Reference 3)		
Well site acreage	Uses Henry Petroluem estimate of 320 acres (Reference 3)	Henry Petroleum presentation estimates average well site size at 320 acres (Reference 3)		
Estimated proportion of wells not pursued because of difficulties with the permitting process.	Estimated 5% of wells not pursued because leases are lost due to project delays. Higher Impact scenario assumes 15%.	One small independent operator (who requested anonymity) reported that his last 14 oil and gas exploration and development prospects averaged over 100 negotiated leases from separate mineral interest owners for each prospect. Of these, this operator believes that from four to six (28% - 42%) would most likely not have been pursued had the new storm water discharge requirements been in place, due to the difficulties the process would cause in the logistics associated with acquiring leases, obtaining permit approvals, scheduling rigs, and meeting lease commitments.		
Estimated impact of lost production from wells not pursued on natural gas prices	Based on a number of previous runs performed by EIA's National Energy Modeling System (NEMS), a rule of thumb was developed to establish the impact of lost natural gas production on future natural gas prices. Based on this review (Reference 9 and 16), it was determined that gas prices increase by $0.13 for every Tcf loss in natural gas production. Analysis of various sensitivity cases in the NPC natural gas study (Reference 14) showed this impact to be over six times as large, with natural gas prices increasing by $0.82 for every Tcf loss in natural gas production. The impact of lost gas production on gas prices was estimated using both sets of assumptions in this assessment.	.		